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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

- - - - In the Matter of - - - -	)	PUC Docket No. 2008-0273
	)	
PUBLIC UTILITIES COMMISSION	)	
	)	
Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs	)	
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HAWAII RENEWABLE ENERGY ALLIANCE'S RESPONSE

TO

THE HAWAIIAN ELECTRIC COMPANIES' PROPOSED SCHEDULE FIT TIER 3 TARIFFS AND AGREEMENT

ATTACHMENTS A &B

AND

CERTIFICATE OF SERVICE

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1. **INTRODUCTION**

By its Order filed on October 24, 2008, the State of Hawaii Public Utilities Commission ("Commission") opened the instant docket, referred to hereafter as the "FIT" docket. The Commission, by its Order filed on November 28, 2008, granted Hawaii Renewable Energy Alliance's ("HREA") motion to intervene filed November 13, 2008 in the FIT docket. In accordance with the Commission's Decision and Order filed on September 25, 2009 in the FIT docket ("D&O"), and its Order Setting Schedule filed on October 29, 2009, as revised by its Order Granting Extension Request filed on March 11, 2010, as may be modified pursuant to the Consumer Advocate's request to the Commission to modify the procedural schedule filed on May 13, 2010, HREA hereby respectfully submits its comments and recommendations regarding the Hawaiian Electric Companies'[1] proposed Schedule FIT Tariffs and Schedule FIT Standard Power Purchase Agreement for Tier 3 filed on April 29, 2010 (collectively, "HECO Tier 3 Proposal").

HREA's comments and recommendations included in this filing are organized and summarized as follows:

[1] Collectively, the "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO").

- ***Section 2*** includes HREA's comments and recommendations on the HECO Companies' financial model and inputs used to calculate their proposed Tier 3 rates. As noted below, HREA supports the HECO Companies' recommendation that In-Line Hydro should not be included in the list of technologies eligible for Tier 3 projects. Section 2 also includes HREA's comments and recommendations regarding the Proposed Costs, Performance Parameters, Financial Assumptions, and Payment Rates for Schedule FIT Tier 3 Wind[2] projects. In general, HREA believes the proposed payment rates are too low to stimulate a market response to achieve the goals of the FIT program, and therefore recommends a higher rate, as further explained below.

- ***Section 3*** includes HREA's comments and recommendations on the non-payment rate terms and conditions of the HECO Companies' proposed Tier 3 Tariff ("Tier 3 Tariff").

- ***Section 4*** includes HREA's comments and recommendations regarding the HECO Companies' proposed Tier 3 FIT Power Purchase Agreement and Attachments ("PPA"). HREA has substantial concerns about many of the provisions contained in the PPA and believes that if the PPA is approved as proposed, it will be extremely difficult for developers to finance and develop projects in the Tier 3 range. Without resolution of these issues, a successful "rollout" of the FIT program is in jeopardy. Further, the goal of the FIT program – to create a predictable and streamlined procurement mechanism to dramatically accelerate the HECO Companies'

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[2] To the extent not specifically addressed in HREA's instant filing, HREA defers to the Hawaii Solar Energy Association ("HSEA") and the Solar Alliance ("SA") regarding their comments and recommendations on the Proposed Costs, Performance Parameters, Financial Assumptions and Payment Rates for the Tier 3 PV FIT projects. Similarly, to the extent not specifically addressed by HREA in this filing, HREA defers to Sopogy regarding the Proposed Costs, Performance Parameters, Financial Assumptions and Payment Rates for Tier 3 PV FIT CSP projects.

purchase of renewable energy, and thereby decrease Hawaii's dependence on foreign oil – may not be achieved.

- ***Section 5*** concludes with a summary of HREA's comments and recommendations regarding the HECO Tier 3 Proposal.

2. HREA'S COMMENTS AND RECOMMENDATIONS REGARDING THE HECO COMPANIES' PROPOSED TIER 3 FINANCIAL MODEL, INPUTS, AND SCHEDULE FIT WIND TARIFFS

HREA respectfully submits for the Commission's consideration the following comments and recommendations regarding the HECO Companies' financial model and inputs used to calculate their proposed Tier 3 rates, as well as comments and recommendations regarding the HECO Companies' Proposed Costs, Performance Parameters, Financial Assumptions, and Payment Rates for Tier 3 Wind FIT projects.

Comments and Recommendations Regarding the HECO Companies' Tier 3 Financial Model and Inputs Used in Proposing Tier 3 Rates

At the outset, HREA notes that it appreciates the HECO Companies' efforts to make the pricing process as transparent and collaborative as possible, for providing the parties with access to the HECO Companies' Tier 3 FIT pro forma cost of generation model (the "Model"), and allowing the parties to comment and submit additional benchmarking information at various stages of the Tier 3 rate determination process. With respect to the Model and inputs used, HREA submits the following comments and recommendations for the Commission's consideration:

Model Input – Interconnection Costs

The HECO Companies used as benchmarking estimates for the cost of performing an Interconnection Requirements Study ("IRS"), $30,000 for projects up to 1 MW in size, $45,000 for projects up to 2.5 MW in size, and $100,000 for projects up to 5 MW in size. See HECO Tier 3 Proposal at 10-12. HREA notes that, based on discussions with its members and other developers,[3] the IRS cost estimates appear underestimated. Based on HREA's discussions with its members and other developers, HREA understands that an IRS for a 5 MW solar project on Oahu cost approximately $140,000, and an IRS for a 100kW wind project on the Big Island cost $125,000. Accordingly, the IRS cost estimates used in the Model should be adjusted to reflect the foregoing figures, which HREA believes represent costs for actual IRS performed for projects in Hawaii.

Model Input – Land Costs

For PV and CSP, the HECO Companies used a range of land costs from $5,000 to $15,000/acre/year. The HECO Companies used the midpoint of $10,000/acre/year with an escalator of 3% a year, applied every 5 years. See HECO Tier 3 Proposal at 12-14.

Since many factors are involved in land valuation, land costs can vary tremendously. For PV projects, land cost assumptions used by the HECO Companies appear low and reflective of land costs for agricultural lands. While every effort should be made to site projects on low-cost lands, assuming a low land cost in the financial

[3] At this time, HREA is unable to identity such members and developers to respect their request to remain anonymous, and due to confidentiality requirements. If the Commission deems it necessary, however, HREA will contact such members and developers to inquire whether they would be willing to disclose information subject to protective order.

model will result in projects being sited only in agricultural lands.

If the goal of the FIT program is to increase the HECO Companies' acquisition of renewable energy, that goal might be better accomplished if generation is geographically dispersed, which may not occur under the current Model, since most agricultural lands are concentrated in the same areas – in Central Oahu, North Oahu, and West Oahu, and on the Neighbor Islands. In addition, PV projects should be encouraged on industrial and Brownfield sites commensurate with principles of highest and best use, since such Brownfield sites are otherwise unusable and tend to be located in industrial areas with a higher demand for energy.

Accordingly, HREA suggests that the PV land cost assumptions also take into consideration estimated lease rents based on land zoned industrial. Based on current market data, industrial land on Oahu typically sells at an average price of $1,306,801 per acre. See Attachment A. Assuming a rate of return of 7% based on the value of a property (which is typical for an industrial lease), using information from publically available listings for parcels on Oahu, land lease costs for industrial land are appear to be closer to $73,181 per acre. Using the 3% escalation rate applied every 5 years as proposed by the HECO Companies, lease rates for PV on industrial land might be calculated as follows:

Example Lease Escalation – PV

Years	Lease
1-5	$73,181
6-10	$84,837
11-15	$98,349
16-20	$114,013

Model – Levered vs. Unlevered Approach

The HECO Companies used a levered approach for its Model, arguing that it is more appropriate since it explicitly recognizes and includes in project cash flows specific financing assumptions. See HECO Tier 3 Proposal at 15-6. As the HECO Companies' themselves acknowledge, individual projects will have very specific financing structures, which do not remain constant, but change significantly with changes in the economy and government policy.

Indeed, assumptions used in the Model will likely change prior to the Commission's approval of the FIT program rates. Use of the levered model introduces a number of complex assumptions, each of which is a variable in a particular project. While many projects will require a certain amount of construction and/or permanent financing, it is extremely difficult to assume a "standard" financing package for projects.

Financing terms and conditions, such as interest rate, loan term, and amortization schedules, will vary depending upon: (a) a lender's risk tolerance and aggressiveness, (b) the project's relative risk level, (c) the experience of the developer, and (d) the creditworthiness of the developer, among other factors. Since it is difficult to select a "standard" financing package for projects, the assumptions used in the levered model can only be estimates. These estimates, however, have a substantial impact upon the resulting energy purchase price.

Accordingly, as recommended by the Blue Planet Foundation in this docket, HREA supports the use of an unlevered model. The unlevered model minimizes the number of assumptions in the financial model and would yield a more realistic rate. Based on HREA's discussions with its members and other developers, it is common practice for developers to use an unlevered approach for its own proforma to assess the viability of a project. Initial project development is typically funded by private investors and financing assumptions may or may not include a construction loan. Initially, developers often assume that the project will be financed on an unlevered basis, and subsequent to commissioning and initial operation of the project, will seek long-term or take-out financing.

Model – Financing Assumptions

Even assuming the Commission deems it appropriate to use a levered model, some of the HECO Companies financing assumptions do not appear to accurately represent financing terms currently available in the market. For example, the HECO Companies assume a debt tenor/term of 20 years. HREA is unaware of any lender that would offer a 20 year loan for a renewable energy project.

In addition, energy projects are not financed like a traditional real estate transactions. There is no mortgage payment of principal and interest. Debt is typically structured off a debt service coverage ratio ("DSCR"), where a project's net operating income must be above or at a negotiated ratio. Based on HREA's discussions with its members and other developers, DSCRs for solar transactions are currently in the 1.3x range. This means that a project's monthly net operating income must be 1.3 times the debt payment, which is not reflected in the Model.

Furthermore, the target internal rate of return ("IRR") / return on equity ("ROE") should be high enough to attract developers and investment to increase renewable energy development in Hawaii. HREA notes that the HECO Companies' benchmark for what a "fair" rate of return appears to be similar to the HECO Companies' rate of return approved by the Commission in recent rate cases, which may not be appropriate for FIT projects.

The HECO Companies' rates of return, once approved, are used as the basis for recovery of costs from rate payers. So long as an expense is within a HECO Company's approved rate base, the HECO Company has a high level of assurance that it will achieve its rate of return. In contrast, developers must assume higher risk, since achieving their return is not as certain.

Moreover, the HECO Companies' Model does not appear to include cash flow timing considerations for the construction or the development period (i.e., development costs, security required under PPA). As a result, the IRRs are likely overstated. Further, a xIRR calculation should be used in order to properly assess the impact of the cash outflows and inflows at or around the time period of financial close to the In-Service Date, but not at the outset, as assumed in the current Model.

Tax Credits

In their Model, the HECO Companies assume that a developer can monetize the full 35% of the State of Hawaii Renewable Energy Technologies Income Tax Credit ("RETITC") at closing. Most developers do not have sufficient Hawaii passive income to offset with the credit and therefore have difficulty monetizing the credit. A developer can monetize the RETITC if it partners with a Hawaii tax partner with an appetite to monetize the entire amount immediately.

However, in the midst of the current financial crisis and slowdown in the Hawaii economy, it is difficult for developers to find investors with sufficient state tax liability to fully monetize the 35% RETITIC. Therefore, for projects in the Tier 3 size that generate substantial state tax credits, it is likely that developers will not be able to fully monetize the RETITC. Project developers will find the 24.5% refundable state tax credit, available only for solar projects, more useful. In addition, HREA notes that the State of Hawaii Department of Taxation recently issued a Tax Information Release in May 2010, which appears to clarify application of the refundable credit for solar, which may change assumptions used by the HECO Companies' in its Model.

HREA Comments on the HECO Companies' Proposed Tier 3 Wind Rate

Overall, HREA has reviewed, analyzed, and evaluated the HECO Companies' proposed Tier 3 tariff rates for wind given the following criteria, which HREA believes is compliant and consistent with specific direction from the Commission in its D&O:

- Projects costs should be based on "typical" or "average" costs[4] to install and operate wind projects in Hawaii. HREA's cost estimates are based on actual projects in Hawaii, bona fide offers to potential clients for purchase of renewable energy from wind projects, existing PPAs, and accepted competitive bids.[5] While HREA disagrees with the HECO Companies on their approach for establishing an "average" project capital cost, HREA's estimates are similar as discussed below.

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[4] See D&O at 62.

[5] See D&O at 84 ("The commission encourages the use of existing Hawaii PPAs and accepted competitive bids to evaluate the reasonableness of cost-based rates."

- Similarly, project performance should be based on average or typical wind sites in Hawaii for Tier 3 wind projects. The HECO Companies base their project performance assumptions on existing large wind projects in Hawaii, which are not representative of a typical Tier 3 wind project. In order to compete with other projects with contract pricing based on avoided costs under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), these existing wind projects are much larger in scale and have been sited in unique areas with higher wind speeds that would likely be unavailable for Tier 3 projects. For example, First Wind's Kaheawa Pastures project on Maui and Tawhiri Power's Pakini Nui/South Point project on the Big Island are located in remote areas that are not near residential/commercial/industrial areas.

For Oahu, the Commission recently approved a PPA for a 30 MW project to be developed by First Wind/Kahuku Wind Power. There are other sites with winds as strong or stronger than Kahuku (e.g., Kaena Point, Keahole Pass, Kahe, Kokohead, and the Koolau Ridgeline), but HREA believes that these sites are not likely to be developed, given expressed or potential community concerns and visual impacts for all such sites, and difficulty of developing and high construction costs likely to be involved for sites on the Koolau Ridgeline.

As most of the optimal wind sites have already been developed, Tier 3 developers will seek the "next best" sites, which will be in locations with lower wind speeds and closer to customer loads. Therefore, the typical Tier 3 project will most likely be developed at a customer's site in with Class 3 wind.[6] Class 3 wind sites average 12 mph at the international standard height of 10m (32ft).

[6] See HECO Tier 3 Proposal at 24-25 (discussing AWEA's wind power classes).

As further explained in detail below, HREA's bases its performance estimates using Class 3 assumptions that correlate to the realistic height of a typical Tier 3 wind project turbine's tower. This is an important criterion for wind developers, as the wind turbine's performance (and capacity factor) increases with tower height due to wind shear effects (the wind speed increases with height above the ground). The turbine's capacity factor (ratio of average power to the turbine's rated generator capacity) is also dependent on turbine-specific design features (i.e., all turbines are not created equal). For example, a turbine on a 10m tower might have a capacity factor of 19%, but when installed on a 40m tower, its capacity factor might be as high as 32%. Similarly, another turbine might have a capacity factor of 20% at 10m, but 34% at 40m. In short, while capacity factors may be design-specific, i.e., more efficient turbine designs will have higher capacity factors, using a taller tower is an effective way to increase the turbine's performance. That said, a lower capacity factor will result in a lower cost of energy and higher required FIT payment rate, and vice versa;

- As explained above, Tier 3 rates should be calculated using <u>financial assumptions</u> based on *current, actual market conditions and existing viable projects.* In addition, for a Tier 3 project to be developed, the assumed IRR/ROE should be sufficiently high to attract investors.

As mentioned earlier, the HECO Companies assume a debt tenor of 20 years, which does not seem to be available in today's financial market. Likewise, given the risk that would be involved in a Tier 3 project as currently proposed, an 11% IRR/ROE is likely too low to attract investors. To compensate for risk involved in developing a Tier 3 project, investors will likely require higher IRRs/ROEs, e.g., in the 15% to 19% range or more.

- Terms and conditions (payment and non-payment related) should be reasonably fair, balanced, and acceptable to a developer. The queuing process must facilitate timely application and approval of FIT agreements. If this is not the case, developers and investors will go elsewhere.

- The HECO Companies have assumed the RETITC can be monetized for wind projects. HREA believes, however, that the RETITC cannot be monetized, as the non-refundable tax equity market in Hawaii and elsewhere is all but "dried up," and there is no refundable credit for wind, as there is for solar. Payment rates should be therefore be higher for wind since the RETITC cannot be monetized.

Detailed Discussion: Wind Project Costs and Performance. For Tiers 1 and 2, the HECO Companies proposed the potential use of a number of wind turbines. For Tier 3, the HECO Companies used data from a 2008 National Renewable Energy Laboratory ("NREL") Mid-Scale Wind Study. See HECO Tier 3 Proposal at 25. As the HECO Companies acknowledged, one of these turbines (Vestas V39) is no longer available. Id. In fact, given the emphasis on the manufacture and use of much larger MW-scale turbines for windfarm applications, there were a limited number of wind turbines suitable for Tier 3 applications in the market. Specifically, for the past several years, many of the major turbine manufacturers have discontinued their Mid-Scale models (generally viewed as greater than 100 kW and less than 1 MW). However, HREA anticipates that wind developers will be able to find turbines suitable for Tier 3 projects in Hawaii.

The HECO Companies' assumed capital costs range from $4,983/kW for a 1 MW project), $4,314/kW for a 2.5 MW project, to $4,049/kW (5 MW project). HREA notes that the cost variation in these scenarios is approximately plus/minus 10% of the estimated project costs of a 2.5 MW wind project. Thus, HREA has selected the 2.5 MW size to develop the "average" costs and performance for Tier 3 wind projects. HREA believes the average costs for a 2.5 MW project to be closer to $4,500/kW, but for discussion purposes, accepts the $4,314/kW figure (the HECO Companies' 2.5 MW project costs, i.e., Scenario C in their analysis) as the average cost for a Tier 3 wind project. Please see Attachment B for additional details of HREA's analysis of Tier 3 project costs.

Nonetheless, there are several potentially significant cost factors for Tier 3 wind developers that HREA believes are NOT included in the Companies' capital cost estimates as follows:

- Costs for a battery system or other storage or firming technology to smooth power if Tier 3 wind projects are required to meet the proposed Tier 3 ramp rate requirements; and

- Potentially significant costs to meet "fault ride through" requirements as proposed.

The following are HREA's observations and concerns about these proposed performance standards and fault ride through ("FRT") requirements in the proposed tariff and PPA:

- To HREA's knowledge, performance standards and FRT capability have only been required for wind projects in Hawaii of 10 MW and larger. Specifically, such performance standards and FRT capability were required for the 10.6 MW Hawi Renewable Development project and the 21 MW Pakini Nui projects on the Big Island, First Wind's 30 MW Kaheawa Pastures project on Maui, and First Wind's 30 MW Kahuku Wind Power project on Oahu recently approved by the Commission.

- The HECO Companies have not conclusively established the necessity of these performance standards and FRT requirements. While the HECO Companies have expressed concern that grid reliability may be compromised by large wind projects, they have not proffered hard analysis to support such concern. HREA has long advocated system ancillary service solutions rather than the project-specific solutions that have been imposed on developers to date. HREA anticipates reliability concerns will continue to be a contentious issue.

- The HECO Companies have presumptively imposed these performance standards and FRT requirements on smaller Tier 3 projects by incorporating them in the proposed Tier 3 PPA. HREA strongly objects to this approach by the HECO Companies and recommends that the Commission approve removal of these provisions in the Tier 3 PPA, or require HECO to establish the necessity of such performance standards (see discussion on the non-payment rate and PPA issues in Sections 3 and 4 below).

- From a technical-turbine design perspective, HREA is aware of only one turbine – the General Electric ("GE") 1.5 MW – that can meet these stringent performance standards.[7] During discussions with the HECO Companies on the Tier 3 wind tariff, the GE 1.5 MW was removed from consideration, as it was considered highly unlikely that developers would select the GE 1.5 due to the high cost of mobilizing a crane large enough to install one to as many as three GE 1.5 MW turbines. HREA agreed with this decision. HREA assumes that this would also be the case for the Clipper 2.5 MW wind turbine, which First Wind has proposed to use for the Kahuku Wind Power project on Oahu.

HREA does not believe any of the turbines considered by the HECO Companies for Tier 3 can meet HECO's proposed performance standards/requirements without extremely expensive equipment to provide the FRT and a battery or other storage/firming equipment for power smoothing.

Detailed Discussion: Financial Assumptions and Recommendations. HREA's comments and concerns regarding financial assumptions used by the HECO Companies to calculate proposed Tier 3 rates are similar to those HREA presented for Tiers 1 and 2.

As explained earlier above, there are a number of financial assumptions used in the HECO Companies' Model, including debt interest rate, debt tenor lender requirements, e.g., minimum debt DSCRs, and anticipated IRRs/ROE. To amplify on previous comments, HREA is not aware of any wind project that has been financed with a 20 year loan. Although the process of financing large-scale wind projects has matured, that is not the case for relatively smaller wind projects, including projects in the Tier 3 range.

In HREA's discussions with developers, a 20-year loan for a wind project is simply not available in today's financial market for a Tier 3 wind project. A 10-year or shorter term loan is more plausible. Likewise, it is unclear whether 9% accurately reflects an "average" or currently available long-term debt rate, or 11% for short-term construction loans. Based on the HECO Companies' financial model, lender DSCR requirements do not appear to have been taken into account.

As the HECO Companies themselves acknowledge, "individual projects will have very specific financing structures", see HECO Tier 3 Proposal at 16, "financing costs

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[7] Both First Wind's Kaheawa Pastures project on the Big Island and Tawhiri Power's Pakini Nui project on

can range widely depending on the factors such as technology, size, and project location", id., and "[f]inancing terms can change quickly depending on the financing climate". Id. at 17. Given the large degree of uncertainty regarding these variables, HREA supports the use of an unlevered approach for estimation of FIT payment rates.

Through discussions with renewable energy developers, HREA understands that the unlevered approach represents the typical approach in assessing projects in the Tier 3 range. As indicated above, initial project development is typically funded by private investors and financing assumptions may or may not include a construction loan. Likewise, in assessing the viability of a potential project, developers often assume that the project will be financed on its balance sheet, and subsequent to commissioning and initial operation of the project, will seek long-term or take-out financing.

The HECO Companies contend that an 11% IRR/ROE should be sufficient to attract investment because the FIT program reduces development risk. Yet, it is reasonable to estimate that it may take at least two years to conclude that project development risks have indeed been reduced in Hawaii by the FIT program. It could also take two months, perhaps only two days, to draw conclusions if there is very little or no uptake (i.e., applications submitted) as the FIT rolls out. This would occur if the "price is not right."

In addition to pricing requirements, in order for the FIT program to be successful, the tariff terms and conditions must be generally acceptable to developers and their investors, developers and investors should be reasonably comfortable that their project will be treated fairly in the queuing process, and in a timely manner. Accordingly, even

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the Big Island use GE 1.5 MW turbines.

if the "price is right," if all of the foregoing factors are not acceptable, very few "may come to the party."

In sum, in HREA's view, in order for the FIT program to achieve its stated purpose – to accelerate acquisition of renewable energy to reduce Hawaii's dependence on foreign oil – FIT rates must be high enough to attract developers and investors, financial assumptions must be reasonable, including the ROE, the queuing process functional, and the tariff and PPA fair and reasonable. The HECO Companies' offer of an 11% rate of return is not likely to attract needed investment, especially combined with uncertainty and risk the developer must assume under the HECO Companies' proposed Tier 3 PPA.

Accordingly, HREA recommends that the Commission set Tier 3 payment rates based on the "unlevered" approach (discussed further below) and allow a higher ROE. HREA anticipates that ROE's in the 15% to 19% range or possibly more would be sufficient to attract developers and investment to accomplish the goals of the FIT program.

Detailed Discussion of Tax Incentives. The HECO Companies assumed that Tier 3 wind developers will be able to monetize the federal Investment Tax Credit ("ITC"), and will elect to receive a 30% grant in lieu of the Production Tax Credit ("PTC"). HREA agrees that Tier 3 wind projects will be eligible for the 30% grant, and that electing to receive the grant will be the preferred approach, as opposed to taking the traditional Production Tax Credit. However, it is not clear at this time whether the grant option will be available past 2010, and if not, whether this will lead to difficulty in obtaining equity investors.

With respect to the State RETITC, the HECO Companies assumed the 20%

RETITC can be monetized for wind projects. However, most developers capable of developing a Tier 3 wind project do not have sufficient Hawaii income to offset, and therefore cannot monetize the RETITC credit. Furthermore, there is no tax credit "refund" option for wind in the RETITC, as there is for solar. Developers therefore will not be able to monetize the RETITC for Tier 3 wind projects.

The HECO Companies also assume that each wind turbine will constitute a "system" and will be eligible for the maximum amount of the RETITC (capped at $500,000). Thus, a Tier 3 project with five turbines could be eligible for a credit of $500,000 for each turbine, or a total of $2.5 million for the project vs. a one system credit of up to $500,000.

HREA understands, however, that tax credits for wind projects to date have only been approved on a one-system per project basis. Although it is conceivable that the HECO Companies' interpretation might be approved by the State of Hawaii Department of Tax in the future, given that the issue is a gray area that has not been clarified by the Department of Taxation, it is not appropriate to assume that each turbine will qualify as a system, especially here, where the HECO Companies have elected to be conservative in its modeling approach. See, e.g., HECO Tier 3 Proposal at 18 (using a 35% debt leverage percentage, which the HECO Companies characterized as conservative).

HREA observes that the potential impact of the use of a 20% refundable credit for each turbine is one reason the HECO Companies' Tier 3 FIT payment rate for wind is proposed at 12 cents/kWh. For example, using the HECO Companies' Scenario C for Tier 3 wind — which assumes a 20-year loan, a 11% IRR, and three turbines, resulting in a 12.1 cents/kWh rate — if the project assumes the use of one turbine instead, the rate increases from 12.1 cents/kWh to 13.8 cents/kWh, which is a *significant* difference, and could likely be a deal-breaker on its own.

As explained above, the model should assume instead that the State RETITC cannot be monetized, which would be consistent with wind developer experience with the RETITC to date, and would result in a rate that more accurately represents a typical or average Tier 3 wind project.

HREA's Discussion and Recommendations for Tier 3 Wind FIT Payment Rates.

HREA refers the Commission to Attachment B for the details of HREA's Tier 3 wind rate analysis. In general, HREA used the same approach it did in its analysis for Tiers 1 and 2, and in all cases, found that there was a remarkable difference in price. HREA first describes its approach in more detail:

- On pages 1 and 2 of Attachment B, HREA inserted the Companies' Tier 3 model summary charts, which show the six scenarios that were used to arrive at their proposed rate of 12.0 cents/kWh. The chart on page 1 includes the key assumptions that were made for each scenario and depicts the results graphically.

- On pages 2 and 3, HREA provides its comments regarding the inputs used to arrive at HREA's recommended average project capital costs and performance. HREA used 2.5 MW as a surrogate size for Tier 3, and HREA's results are similar to the Companies'. Some of the key assumptions are highlighted below:

    - *Capital Costs* – $4,500/kW for capital costs vs. using a range from $4,049/kW to $4,983/kW and selecting an average of about $4,516. Since HREA based its average on a 2.5 MW system, it elected to use the Companies' cost of $4,314/kW for HREA's analysis.

- o *Capacity Factor* – HREA used 32% as the capacity factor vs. the average of the Companies' range of 28% to 36%. It should be noted here that the Companies' 2.5 MW capacity factor was also 32%.

- o *O&M Costs* – HREA used $40/kW/year, which is the high end of the Companies' range.

- o *Financial Analysis* – HREA performed three cases: two unlevered and one levered, which are discussed in further detail below.

- o *Tax Treatments* – HREA did not include the RETITC, while the Companies' did.

<u>Discussion: Financial Assumptions and Results</u>. On page 4 of <u>Attachment B</u>, HREA has provided a summary of two results using an unlevered approach. The first scenario assumes 0% debt and a ROE/internal rate of return of 15%. The second scenario assumes 0% debt and a ROE/internal rate of return of 19%. Both scenarios assume that the developer cannot monetize the RETITC. The resulting payment rates are **$25.1 cents/kWh for an IRR/ROE of 15%** and **31.5 cents/kWh for an IRR/ROE of 19%.**

For comparison, HREA also used a levered approach as illustrated on page 5 of <u>Attachment B</u>, with input assumptions as follows: no monetization of the RETITC, a 10 year debt loan, and a 19% IRR/ROE, which results in a rate of **23.5 cents/kWh**.

HREA therefore recommends that the Commission establish the Wind Tier 3 FIT payment rate using the range of **25.1 cents/kWh to 31.5 cents/kWh**. While this rate is significantly higher than that proposed by the HECO Companies, it represents the rate at which HREA believes projects will move forward in today's market. In contrast, the HECO Companies' proposal of 12.0 cents/kWh is likely too low to generate activity.

3. COMMENTS AND RECOMMENDATIONS ON NON-PAYMENT RATE TERMS AND CONDITIONS OF THE HECO COMPANIES' PROPOSED TIER 3 SCHEDULE FIT TARIFFS

HREA submits for the Commission's consideration the following comments and recommendations regarding the HECO Companies' Tier 3 Tariff:

- Tariff § B(1)(b) – Section B(1)(b) of the Tier 3 Tariff prescribes limits on the size of eligible Tier 3 facilities and in connection with the same, refers to "system peak load." HREA suggests that language be added to clarify that "system peak load" means the applicable Company's total system peak load from the previous year,[8] as well as providing the source of such information, so that applicants can determine with certainty the applicable limitation before submitting an application.

- Tariff §B(5) – Section B(5) provides that the Seller[9] may not sell energy to third parties during the term of the agreement or renegotiate with the Company for any changes to the Tier 3 PPA during the term. The limitation on sales to third parties (which also appears in the PPA) should exclude circumstances where the Company breaches its obligation to purchase energy from the facility, curtails deliveries from the facility, or otherwise does not purchase all of the energy from the facility. In addition, this subsection should be clarified to provide that the Seller may renegotiate the PPA under certain circumstances, e.g., where a change in performance standards (and pricing) may be necessary, or where the Commission, in reviewing the FIT program

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[8] See D&O at 41 ("In determining project size limits, the commission favors . . . the competitive bidding threshold of 5 MW for Oahu and 2.72 MW each for Maui and Hawaii. To be precise, the exemption from the competitive bidding is for 'generating units with a net output available to the utility of 1% or less of a utility's total firm capacity, including that of independent power producers, or with a net out output of 5 MW or less, whichever is lower.'")

[9] HREA notes that it has used the terms "developer" and "Seller" interchangeably for purposes of this filing.

after the initial 2 year phase, determines that changes to the FIT program are necessary to better accomplish the goals of the program.

- Tariff §L(2) – Section L(2) provides in part that "[a] reservation fee shall be submitted by the Seller to the Company within five business days after successful submission of the application for service under this Schedule FIT." The term "successful submission" should be clarified. For example, it is unclear whether "successful submission" means when an application is successfully submitted via the HECO Companies' queuing website (i.e., not bounced when submitted), or upon acceptance of the application by the appropriate HECO Company (in which case, notice of the company's acceptance should be delivered to the applicant).

- Tariff §L(2) – Section L(2) requires the Seller to submit a reservation fee in the amount of $15/kW after submission of an application, which will be refunded to Seller following the In-Service Date, if the Seller meets the Guaranteed In-Service Date. HREA suggests that the reservation fee should also be refunded if the PPA is not executed for certain reasons (e.g., because of a lack of necessary transmission capacity to support interconnection of the facility, or a finding that a project is not feasible after the Interconnection Requirements Study indicates that costs required to support the interconnection would be much higher than anticipated).

4. COMMENTS AND RECOMMENDATIONS REGARDING THE HECO COMPANIES' PROPOSED TIER 3 POWER PURCHASE AGREEMENT

As HREA noted in its Motion to Intervene filed on November 12, 2008, HREA's membership is comprised of companies, consultants, and agents involved in or considering developing, manufacturing, marketing, selling, installing, and maintaining renewables in Hawaii. The comments and recommendations set forth below are intended to ensure that HREA's member's interests are adequately protected. To the extent that HREA has long advocated increasing the use of renewable energy in Hawaii, its interests are consistent with the overall policy objective of the FIT program – to encourage the accelerated acquisition of renewable energy in Hawaii by creating a procurement mechanism with certain and predictable terms under which renewable energy will be purchased by the utilities in order to reduce Hawaii's dependence on foreign fossil fuels. To that end, the following comments and recommendations are offered with particular emphasis on assessing whether the PPA contains terms and conditions that would be reasonably acceptable to renewable energy developers, and whether Tier 3 projects will be financeable.

PPA Definitions

- "Annual Contract Energy", PPA at 2[10] – "Annual Contract Energy" is defined as a fixed amount to be specified by Seller as its estimate of expected annual average electric energy deliveries to the Company under the PPA over the term. Because a Facility's capacity may degrade over time, the Seller should have the option of specifying a degradation factor or specifying different amounts of energy for each year (perhaps in an Attachment to the PPA).

- "Good Engineering and Operating Practices", PPA at 6-7 – "Good Engineering and Operating Practices" or "GEOP" is the standard of practice imposed by the PPA upon the utility and Seller with respect to Seller's Facility. The definition

[10] References are made to PPA page numbers as they appear on the PPA attached to HECO's Tier 3 Proposal. Unless otherwise specified, capitalized terms used in this section have the meaning set forth in the PPA.

purports to be the standard employed by the "electric utility industry for similarly situated U.S. facilities," which on its face appears to be a balanced standard employed by other utilities in the United States. While the term "GEOP" is meant to survey the practices currently used elsewhere in the United States, the definition proposed by the HECO Companies goes further by providing that GEOP "consider[] [the] Company's isolated island setting and other characteristics" appropriate for an "island system." Such language effectively converts GEOP to a HECO Company standard which the HECO Companies may change from time to time, without notice to developers, depending on how the HECO Companies decide to operate their systems. GEOP should be a standard which any operating utility can reasonably determine and apply to its conduct, but that is not the case here. The HECO Companies' definition of GEOP implicitly excludes all other utility systems whether islanded (Alaska, Virgin Islands, Puerto Rico, Block Island) or bulk interconnected (mainland United States).

HREA therefore recommends that the phrase "and other characteristics" be removed from the definition, since such language does not clarify the definition, but simply changes what should be a balanced standard to apply only to the HECO Companies' systems. In addition, the definition of GEOP includes a number of clarifying provisions that apply only to the Seller's Facility (e.g., adequate materials, sufficient personnel, performance of maintenance, etc.). These standards should also apply to the HECO Companies conduct and facilities in connection with the Seller's Facility.

- <u>"Environmental Credits", PPA at 5</u> – The definition of "Environmental Credits" should be clarified to reflect that in addition to tax credits, other types of payments are excluded from the definition. HREA recommends that the term "tax credits" appearing at the end of the definition be replaced with the following: "(i) any energy, capacity, reliability, or other power attributes from the Facility; (ii) any state and federal production tax credits, investments tax credits, and any other tax credits which are or will be generated by the Facility; or (iii) any cash payment, grant, or refund relating to the ownership, development, construction, operation, maintenance, or financing of the Facility."

Article 1 – Parallel Operation, PPA at 14

Under the PPA, parallel operation of the Seller's Facility is contingent on satisfactory completion, as "determined solely by Company" of the Acceptance Test. If a HECO Company is permitted to deny a determination of satisfactory completion of the Acceptance Test in its "sole" discretion, the Company may effectively deny placing a project in service for any reason whatsoever. HREA therefore recommends that the approval standard be a "reasonable" standard instead.

Article 6 – Forecasting

- Section 6.1, PPA at 19 – Section 6.1 requires the Seller to provide, for Company planning purposes, a forecast of each month's average-day electric energy production from the Facility, by hour, which forecast shall include an expected range of uncertainty based on historical operating experience, and shall be updated on a monthly basis by notice given to the Company. Although monthly forecasting reports may be helpful for the HECO Companies' planning purposes, this requirement is overly burdensome on the Seller, especially for intermittent resources, which vary significantly with changes in the weather. It would be difficult for a Seller to accurately predict weather a month out.

HREA acknowledges that Section 6.5 provides that the forecasts required under Article 6 shall be non-binding, good faith estimates only. Section 6.5 also provides, however, that for wind projects, the Seller is required to prepare forecasts using models or services acceptable to the HECO Companies and available at a commercially reasonable cost, which imposes a requirement mores stringent than a good faith estimate. In addition, it is unclear what cost would constitute a "commercially reasonable cost", and whether the cost of such forecasting equipment or software is reflected in the HECO Companies' proposed rate calculation.

- Section 6.2, PPA at 19 – Section 6.2 requires the Seller to provide the Company with an hourly forecast of deliveries for each hour of day for the ensuing week. The Seller is further required to update a forecast any time information becomes available indicating a change in forecast of generation of Actual Output from current forecast, but no more frequently than once per hour. Requiring the Seller to update its forecast for any change places an unreasonable burden upon the Seller, particularly where the change has no material or practical effect upon the generation of Actual Output. HREA recommends instead that this section be revised to require the developer to provide updates where there are "material" changes. Alternatively, a threshold might be specified, e.g., when Actual Output would change by more than 10%.

- Section 6.3, PPA at 20 – Section 6.3 provides that in connection with annual and weekly forecasts, Seller shall also provide to Company, data and information required by Company to conduct its own annual and weekly forecasts for all variable generation facilities on Company system. The HECO Companies should clarify "data and information" is required. Without specificity, the developer runs the risk of failing to provide information the HECO Companies deem necessary, which can lead to miscommunication and disputes. If the HECO Companies are unable to identify the "data and information" required, Section 6.3 should be removed.

Article 8 – Continuity of Service (Curtailment)

The provisions of Article 8 represent, perhaps, the area of most significant concern to HREA and its developer members. HREA acknowledges that "[a]s isolated island grids, the HECO Companies' systems have no export outlet for excess energy",[11] and where conditions with excess energy begin to develop, curtailment may be necessary to ensure system reliability. However, the HECO Companies' broad power to curtail projects under Article 8 runs counter to one of the stated goals of the FIT program – to create a procurement mechanism with certain and predictable terms under which renewable energy will be purchased by the HECO Companies. Curtailment of an as-available project would have an undeniable financial effect on a project. If energy is curtailed, the Seller would receive less in payment. Uncertainty as to when and under what circumstances a project may be curtailed places significant and undue risk on the Seller, which will make it extremely difficult for a Tier 3 project to be financed. HREA provides the following comments and recommendations regarding specific provisions under Article 8:

- Section 8.1, PPA at 20-21 – Under Section 8.1, the Company can curtail deliveries of electric energy if the Company determines that such curtailment is necessary because of a system emergency, forced outage, certain operating conditions, light loading conditions, or if the Facility does not operate in accordance with GEOP, which the Company System Operator determines at his or her sole discretion.

[11] See D&O at 70.

It may be appropriate for the System Operator to have the discretion to require curtailments of energy delivery under certain circumstances; however, the actions of the System Operator should be held to a reasonableness standard. As currently drafted, the System Operator may unnecessarily curtail a project with impunity, or may frequently incorrectly or improperly curtail, all with no consequence to the Company or System Operator, but with substantial adverse financial consequences to the Seller.

- Section 8.2, Negative Avoided Cost, PPA at 21 – Read literally, this section allows the Company to curtail energy deliveries from a project, if due to operational circumstances, the Company can generate energy for less than its cost of purchasing the energy from the Seller. This section is contrary to the intent of the FIT program – to encourage the accelerated acquisition of renewable energy in Hawaii – and when read with other provisions of the PPA, is likely to jeopardize the viability of a Tier 3 project. Pursuant to the Commission's D&O, and Section 2.1 of the PPA, the Seller must sell all of its Actual Output of electricity to the Company. Article 20 of the PPA further prohibits the Seller from selling electricity to any third party. Yet, the HECO Companies are permitted to generate lower cost energy (most likely using fossil fuels) and leave the developer's project idle and investment wasting. This structure has created substantial concern among lenders and investors. The possibility of these financially based curtailments (not reliability based curtailments), which would impair project returns, is a significant source of risk and jeopardizes project viability in the eyes of a lender or investor.

In their March 4, 2010 responses to PUC-IR-311, the HECO Companies asserted that this subsection should be included in the Tier 1 and 2 PPAs, since such language appeared in previous negotiated PPAs the Commission approved. The

HECO Companies may argue that developers, lenders, and investors are not concerned with this subsection since PPAs for these projects were signed and these projects were financed. However, such argument ignores the reality that the prominent projects developed in the last several years – the 30 MW Kaheawa Pastures wind project on Maui, the 1.5 MW photovoltaic project on Lanai, and the 500 kW CSP project on the Big Island – were, based on HREA's understanding, financed through Qualified High Technology Business ("QHTB") tax credits,[12] and not traditional debt financing. Due to recent changes in Hawaii laws relating to the availability of QHTB tax credits, it is highly unlikely that future renewable energy projects under the FIT will be financed through QHTB credits. Instead, FIT projects will likely rely upon traditional debt financing and undergo rigorous scrutiny from lenders.

In their March 4, 2010 responses to PUC-IR-311, the HECO Companies also contended that the authority for this subsection is based on 18 CFR § 292.304(f) (periods during which purchases not required) and Federal Energy Regulatory Commission Order No. 69 (Final Rule Regarding the Implementation of Section 210 of the Public Utilities Regulatory Policies Act of 1978) ("FERC Order 69"), which provide that a utility may not curtail as-available resources for economic reasons, but may curtail for operational circumstances that occur under light loading conditions.

A utility retains such right to curtail where the utility is required to purchase the output of a Seller's facility as a Qualifying Facility under PURPA. A FIT project would exist by virtue of the Commission's FIT program, which is based on statute, not on PURPA, and a PPA, which sets forth the parties contractual obligations. Indeed, FERC Order 69 provides that 18 CFR § 292.304(f) does not override contractual

[12] Under Hawaii Revised Statutes 235-110.9, investments in qualified high technology businesses may

obligations incurred by the utility. In the absence of Section 8.2, the HECO Companies would not have the right to curtail a FIT project for operational circumstances.

By citing 18 CFR § 292.304(f) in the PPA, the HECO Companies have effectively tied back into a FIT project, as a contractual right, the right to curtail under PURPA, which right would otherwise not exist. HREA therefore recommends that Section 8.2 be removed from the PPA.

- Section 8.3, PPA at 22 – As indicated by the HECO Companies in their March 4, 2010 responses to PUC-IR-311, the HECO Companies contend that Section 8.3 adequately addresses developer, lender, and investor concerns regarding the HECO Companies' right to curtail under Section 8.2. Section 8.2 provides that "[t]his Article 8 (Continuity of Service of this Agreement is not intended to permit Company to require Seller to curtail, interrupt or reduce deliveries of electric energy based on Company's economic dispatch (for example, as a consequence of Company's filed Avoided Energy Cost Data being lower than the applicable price per MWh paid to Seller under this Agreement, or to make purchases of less expensive electric energy from a Qualifying Facility)" (emphasis added).

The language "is not intended to" is not a clear statement that the HECO Companies will not curtail energy deliveries for economic dispatch or economic reasons. If Commission determines that Section 8.2 should be deleted from the PPA, then Section 8.3 should be similarly deleted. If, however, the Commission determines that Section 8.2 should be retained, then Section 8.3 should be modified for clarity to provide that Article 8 "shall not permit" the Company to curtail for economic dispatch or economic reasons.

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qualify as investment tax credits.

- Curtailment Priority, Article 8 and Attachment B – Assuming the Commission determines that the HECO Companies will have the right to curtail Tier 3 projects under Article 8, Attachment B, Sections 2(f)(ii) and (v) provide criteria for curtailment priority. Specifically, FIT facilities will be grouped together in one or more blocks, where each block consists of all curtailable facilities that applied for a FIT project in the same release phase. It is not clear, however, how curtailment will be applied among facilities within the same group. HREA therefore suggests that the PPA include language clarifying that curtailment be applied pro rata to all facilities with the same priority date.

Article 9 – Personnel and System Safety, PPA at 22-23

Article 9 provides in relevant part that the Company System Operator shall have the sole discretion to curtail or disconnect a Facility if Company personnel or the Company's System is endangered. While it is appropriate for the System Operator to maintain discretion to require curtailment under certain circumstances, under Article 9 as currently drafted, the System Operator may unnecessarily curtail a FIT project with impunity or may frequently incorrectly or improperly curtail a project, all with no consequence to the HECO Companies or the System Operator. The actions of the System Operator should be held to a reasonableness standard instead.

Article 12 – Term of Agreement, PPA at 24-25

In general, Article 12 sets the Initial Term of the PPA (i.e., 20 years unless terminated sooner), and an Extended Term, which applies if the Company elects to purchase energy from the Facility after expiration of the Term. It is unclear, however, what rights the parties have following termination. For example, if the Company determines that it will not exercise its right to purchase energy beyond the Initial Term, it is unclear whether the developer may then be permitted to sell its energy to a third party. Therefore, the PPA should be revised to clarify that the Seller may sell energy to any person after the expiration or termination of the PPA and that the interconnection provisions contained in the PPA survive such expiration or termination. Such clarification is especially important to ensure that the Facility remains viable and is not stranded in the event of a premature termination of the PPA. Such clarification will also reduce the developer's risk and facilitate financing of the project.

Article 13 & Attachment L – Construction Milestones, PPA at 25-27

- Under Section 13.2 of the PPA, the Seller is required to meet certain Reporting Milestones described in Attachment L. The PPA leaves the date of such Reporting Milestones blank. It is unclear from the PPA which party will determine what those dates are. Presumably, a developer will propose dates based on its project schedule, which the Company must ultimately approve, i.e., the dates are subject to negotiation.

One of the stated goals of the FIT program is to accelerate the HECO Companies' acquisition of renewable energy by allowing a developer to sell energy according to standard terms and conditions which provide a degree of certainty. If milestone dates are left open to negotiation, such open-endedness would run counter to the certainty the FIT program is intended to achieve. Furthermore, if negotiation of milestone dates occurs at the end of the FIT PPA process (as is typically the case in bilateral PPA negotiations), the developer would be left with unequal bargaining power. At that stage, the developer would have invested significant resources to secure land, entitlements, and necessary permits, and would be reluctant to argue against the utility's preference for certain milestone dates (even if unreasonable) for fear of losing the potential project.

The problem is compounded by the possibility that if the Seller fails to meet any Reporting Milestone, such failure may be considered an Event of Default under Section 15.2(E) of the PPA. HREA acknowledges the difficulty of determining milestone dates without a completed IRS. In order to eliminate uncertainty, perhaps the milestone dates should be contingent on the results of an IRS, e.g., ___ months after the IRS is completed, with an express limit on the amount of time to complete an IRS.

- Under Section 13.3, the Seller must achieve the Guaranteed In-Service Date, which presumably will be determined by the parties. If the Seller fails to meet the Guaranteed In-Service Date, and the failure is due to a Force Majeure event, the Seller is entitled to a grace period of the lesser of 180 days or the duration of the Force Majeure event. Upon termination of the grace period, the Company has the right to terminate the PPA. It is conceivable, however, that a Force Majeure event can extend beyond 180 days. That is inconsistent with Section 21.4, which provides for deferment of termination damages for an Event of Default caused by a Force Majeure event up to 365 days. Section 13.3(B) should therefore be revised to provide that if the Seller fails to meet the Guaranteed In-Service Date because of a Force Majeure event, Seller will be entitled to a grace period of the lesser of the duration of the Force Majeure event or 365 days.

Section 13.3 should further be revised to provide a day-for-day extension of the Guaranteed In-Service Date to the extent that any delay in achieving the In-Service Date is attributable to an act or omission of the Company. Such provision is necessary, since achieving the In-Service Date is dependent on certain actions only within the Company's control (e.g., issuing a request for proposals for consultants to perform an IRS and selecting a consultant, reviewing and providing approvals for engineering and construction plans, etc.).

Article 14 – Credit Assurance and Security, PPA at 27-30

- Section 14.4 and 14.5, Amount and Form of Operating Period Security, PPA at 30 – Section 14.4 requires the Seller to provide an Operating Period Security of $40/kW based on a project's capacity, by Letter of Credit or cash, to guarantee the Seller's performance of the Seller's obligations under the PPA. For a 5 MW project, the Operating Period Security would amount to $200,000. It does not appear that the cost of obtaining a Letter of Credit has been incorporated in HECO Proposed Tier 3 rates.

- Section 14.8, Establishment of Operating Period Security, PPA at 28 – Section 14.8 provides that the Operating Period Security shall be maintained at the Seller's expense, and shall be originated by or deposited in a financial institution or company ("Issuer") *acceptable to Company*. As drafted, the HECO Companies would essentially maintain the sole discretion to approve an Issuer, which may render a project difficult to finance. Instead, a reasonableness standard should be imposed upon the HECO Companies with respect to their rights to approve the Issuer of the developer's Operating Period Security.

- Former Section 14.12, Facility Lender Related Requirements – A previous draft of the PPA circulated by the HECO Companies contained various provisions related to Facility lender related requirements (e.g., requiring the Seller to execute a Security Agreement to secure Seller's performance of its obligations under the PPA, requiring the Seller to deliver to Company favorable legal opinions of counsel satisfactory to Company that the Security Agreement has been duly authorized), which would have made it more difficult for a developer to obtain financing for a project. HREA appreciates the HECO Companies' deletion of former Section 14.12. The taking by the Company of a security interest in the Facility, even is subordinate to the other lender's debt interests in the Facility, would, from such other lender's perspective, increase such other lender's risk. Moreover, such security interest requirements would increase the Seller's transaction costs, while not materially enhancing the HECO Companies' remedies in the event of a default by the Seller.

Article 15 – Events of Default, PPA at 30-33

- Section 15.1(B), PPA at 30 – Section 15.1(B) currently provides that a Seller Event of Default has occurred if, at any time subsequent to the In-Service Date, the Seller fails to provide electric energy to Company for a period of 365 or more consecutive days, unless such failure is caused by the inability of the Company to accept such electric energy. Section 15.1(B) should be revised to add that the Seller's failure to provide energy is excused if: (a) Company breaches its obligations under the PPA, (b) energy is curtailed by the Company, or (c) any Force Majeure event or condition.

- Section 15.1(C), PPA at 30 – Section 15.1(C) provides that failure by the Seller to deliver from the Facility at least 60% of the Annual Contract Energy for a period of three consecutive years constitutes an Event of Default. Section 15.1(C) should be clarified to indicate that for purposes of Section 15.1(C), the following are not counted as a deduction for purposes of the 60% calculation: (a) energy not delivered due to any breach by the Company of its obligations under the PPA, (b) energy not delivered due to any curtailment by the Company, or (c) energy not delivered due to any Force Majeure event or condition.

- Section 15.1(D), PPA at 30 – Section 15.1(D) provides that if at any time during the Term, the Seller fails to satisfy the Credit Assurance and Security requirements under Article 14, such failure constitutes an Event of Default. Section 15.1(D) should be revised to add a reasonable cure period (perhaps 30 days). Otherwise, Section 15.1(D) could be triggered by a downgrade of the Issuer providing a Letter of Credit, and the Seller may need additional time to obtain a Letter of Credit from a different Issuer (assuming the Commission determines that an Operating Period Security is reasonable).

Article 16 – Damages in the Event of Termination by Company, PPA at 33-34

Under Section 16.2, if the Seller defaults under the PPA resulting in an Event of Default, and the Company terminates the PPA as a result, the Seller is liable for liquidated damages of $40/kW based on the capacity of the project (which is the same amount as the Operating Period Security). Under Hawaii law, a liquidated damages provision that is not specific and does not bear a "reasonable relation" to any actual damages suffered is likely unenforceable. See Gomez v. Pagaduan, 613 P.2d 658, 662 (Haw. Ct. App. 1980). For a 5 MW project, liquidated damages would total $200,000, which does not appear to be reasonably related to actual damages the

HECO Companies would suffer. Again, while the HECO Companies may be responsible for penalties for failing to meet RPS requirements, such penalties are speculative and should not be considered damages until assessed. Accordingly, Article 16 should be removed.

Alternatively, the provision might provide that the amount of liquidated damages, which should be set at an amount reasonably related to damages the HECO Companies would actually suffer, decreases by 5% each year, such that at the end of the Term, liquidated damages would be zero. Such graduated decrease in liquidated damages would be consistent with the reasonable assumption that at the end of the Term, the PPA would terminate, at which point the Company should not suffer damages.

Furthermore, HREA notes that neither Article 16, nor any other provision of the PPA, specifies liquidated damages for an Event of Default by Company. The PPA should be clarified to provide that Seller, subject to the terms and conditions of the PPA, may pursue any available remedies at law or equity in the event of a Company Event of Default.

Article 17 – Indemnification, PPA at 34-36

Section 17.2 provides that Company shall indemnify, defend, and hold the Seller harmless for any act/omission of "Seller", which is likely an error. It would not make sense for the Company to indemnify the Seller for the Seller's acts and omissions. Accordingly, the term "Seller", appearing four lines from the bottom of page 36 of the PPA, should be replaced with "Company".

Article 20 – Sale of Energy to Third Parties, PPA at 40

HREA recognizes that the prohibition on the sale of energy to third parties is consistent with the Commission's Interim Decision and Order. However, since the HECO Companies have broad curtailment rights under Article 8, during times of curtailment, or when the HECO Companies do not otherwise purchase all of the project's energy output, the developer is left with no off-taker of energy leaving the project and investment idle. At the very least, the developer should be permitted to: (a) consume energy produced at the project for the developer's own use; (b) transmit energy to the developer's other facilities or properties for use by the developer; and/or (c) transmit energy to the developer's affiliates' and/or subsidiaries' facilities or properties for use by such affiliates or subsidiaries.

Article 21 – Force Majeure, PPA at 40-43

- Sections 21.1 and 21.2, Definition and Exclusions from Force Majeure, PPA at 40-41 – Force Majeure is intended to provide a party with relief from its inability to perform its obligations under a contract when such failure is due to an event outside of the control of the party claiming Force Majeure. While the definition set forth in Section 21.1 conforms to that general principle, Section 21.2 designates conditions that are specifically excluded from the definition of Force Majeure. Many of the exclusions are also events or circumstances outside of the control of either party and should be included in the definition of Force Majeure (or removed from the list of exclusions). For example, if a developer's fails to secure a necessary permit because a governmental agency does not issue the permit (for reasons not due to any act or omission of the developer), such failure should be considered a Force Majeure event. Similarly, if a third party files a frivolous complaint against a developer, which is outside of the control of the developer, such litigation should be considered a Force Majeure event. Accordingly, Sections 21.2(D) and 21.2(H) should be removed.

Alternatively, Section 21.2(D) might be amended by appending at the end of such subsection the following language – "unless Seller has made commercially reasonable efforts to obtain such Permits or approvals." Likewise, the following language should be appended to Section 21.2(H) – "unless the Party claiming the Force Majeure has made commercially reasonable efforts to resolve such litigation or administrative or judicial action so as to reduce or limit its impact on such Party's ability to perform." HREA also notes that certain force majeure events included in the RPS statute, Hawaii Revised Statutes ("HRS") § 269-92(d) (e.g., actions of governmental authorities, HRS § 269-92(d)(6), and the inability to obtain permits or land use approvals for renewable energy projects, HRS § 269-92(d)(8)), which the HECO Companies may claim, are not afforded to the Seller under the PPA.

- Section 21.3, Force Majeure/Satisfaction of Certain Conditions, PPA at 41-42 – Certain liabilities may be deferred under the PPA for a Force Majeure event, provided the conditions set forth in Section 21.3 are satisfied, which include, among other things, that the Non-performing party provides the other party with written notice of a Force Majeure event within 48 hours after the Force Majeure event begins. See Section 21.3(A), PPA at 42. The requirement that written notice be delivered within 48 hours after the Force Majeure event begins is not realistic or reasonable because the party claiming Force Majeure may not know a Force Majeure event has begun until some period of time has elapsed. For example, in the case of an earthquake, even after inspecting the Facility in accordance with good engineering and operating practices, the Seller may reasonably determine that there is no damage to the Facility.

Yet, it is plausible that some form of inchoate damage may manifest and be discovered later. The PPA as drafted would exclude such event as a Force Majeure. To avoid this unintended result, Section 21.3(A) should be revised to provide that the Non-performing party claiming Force Majeure is required to give the other party notice of the Force Majeure event only after the Non-performing party becomes aware of the condition.

- Section 21.4, Force Majeure, In-Service Date, PPA at 50 – Section 21.4 provides that if a Force Majeure event causes Seller not to achieve the In-Service Date, then Seller will not be relieved of Termination Damages for early termination under Section 16.1 (Termination Due to Failure to Meet the Guaranteed In-Service Date). This provision is inconsistent with other provisions of the PPA. Section 16.1 provides that if the PPA is terminated by the Company pursuant to Section 13.4 (Termination), the Company shall be entitled to retain the Reservation Fee. Force Majeure is intended to defer liability, but Section 16.1 assumes that the PPA has been terminated by the Company. Once the PPA has been terminated, the Seller's obligation to meet the In-Service Date cannot be deferred. Accordingly, Section 21.4 should be clarified to provide that if, at the end of the Force Majeure period, the Seller has not achieved the In-Service Date, then the Company may terminate the Agreement, and upon termination, the Company will be entitled to retain the Reservation Fee.

- Section 21.4, Force Majeure, In-Service Date, PPA at 42 – Section 21.4 provides that if a Force Majeure condition or event causes Seller not to achieve the In-Service Date, liability will be deferred to the extent of the grace period provided in Section 13.3(B), i.e., 180 days. A 180-day deferment period may not be sufficient for Force Majeure events or conditions. This provision is also inconsistent with Section 21.5, which allows deferment of Seller-liability for an Event of Default for the lesser of the duration of a Force Majeure event or 365 days. The grace period under Section 13.3(B) should therefore be revised to 365 days.

- Section 21.5, Force Majeure, Events of Default, PPA at 43 – Section 21.5 specifies that events or conditions of Force Majeure defer the liability for Termination Damages for a maximum of 365 days. Although liability for Termination Damages is deferred, Force Majeure will not defer termination of the PPA itself, which is inconsistent with market practice and substantially increases the risk of termination to the Seller (which could affect its ability to obtain financing). Accordingly, this provision should be revised to specify that the termination itself, rather than just the liability for Termination Damages, shall be deferred during an event or condition of Force Majeure. In addition, Section 21.5 should be amended to provide that in the event of a termination resulting from an event or condition of Force Majeure, no Termination Damages shall be payable, since, by definition, any such termination shall not be the fault of the party subject to the event or condition of Force Majeure.

Article 28 – Dispute Resolution, PPA at 53-59

Sections 28.1 and 28.2 require a Management Meeting and mediation before submitting a claim to binding arbitration. Section 28.2(C) specifies that a notice initiating arbitration shall not be valid or effective to the extent that the claim(s) in such notice would be barred by the applicable statute of limitations or laches. The language should be revised to clarify that an action by a party to identify a dispute to the other party pursuant to Article 28, including proposing a Management Meeting to discuss the dispute, shall toll the applicable statute of limitations. Similarly, the language should be clarified to provide that the doctrine of laches shall not apply to any period subsequent to such action, provided that the party complies with the procedures in Article 28.

Article 22 – Warranties and Representations, PPA at 43-44

Section 22.2 requires that Seller represent and warrant, as of the In-Service Date, that its Facility is a qualified renewable resource under RPS. Section 22.2 therefore requires the developer to make a representation that the project complies with the RPS statute as it will exist at some point in the future. The developer cannot know, as of the date it signs the PPA, what the Hawaii RPS statute will require when the project is placed in service at some point in the future (which may be two years from the date of execution). Section 22.2 should be revised to reflect that Seller's RPS representation is made with respect to the RPS as it exists on the "Execution Date".

Article 23 – Performance Standards, PPA at 44-49

- Sections 23.1 and 23.2, PPA at 44-45 – Section 23.1 generally provides that certain Performance Standards may be revised during the Term of the PPA for various reasons, including, without limitation, changes to penetration levels of intermittent renewable resources on the Company System, changes in technology, changes in to Company-owned generation resources, etc. Under Section 23.2, a Performance Standards revision may be initiated only by the Company at its sole discretion, and the Company has no obligation to evaluate a performance standards proposal submitted at Seller's own initiative. It may be necessary to revise performance standards; however, both parties should be given the right to request a revision of Performance Standards.

- Sections 23.5 and 23.7, Performance Standards, Failure to Reach Agreement, PPA at 46 – Similarly, Section 23.5 provides that if the Company and the Seller are unable to agree upon and execute a Performance Standards Revision Document, only the Company has the option of declaring a failure to reach agreement and submit the dispute to an Independent Evaluator. Section 23.7 further provides that the rights granted to Company under Sections 23.4 and 23.5 are exclusive to the Company, and that the Seller shall have no right to initiate negotiations of a Performance Standards Revision or dispute resolution. It is unreasonable that only the HECO Companies retain such rights. It would be more appropriate for both the Seller and the Company to be able to initiate a Performance Standards revision and declare and submit a dispute for resolution.

- Section 23.10, Performance Standards Dispute, PPA at 27 – Section 23.10 provides that if the Company declares a Performance Standards Dispute, the dispute will be submitted to an Independent Evaluator for resolution. Section 23.10 further provides that if an Independent Observer retained under the Competitive Bidding Framework is qualified and available, the Commission may appoint the Independent Observer to serve as the Independent Evaluator. It is unclear why the Independent Observer under the Competitive Bidding Framework is referenced. It would be more appropriate to have the Independent Observer in the FIT docket to be considered instead.

Article 24, Financial Compliance, PPA at 49-52

Article 24 generally provides that the HECO Companies, to ensure compliance with various accounting requirements and federal laws, may audit the developer's financial records. An audit is a very intrusive activity that will consume certain internal resources of the developer, as well as require the developer to expose its private, confidential, and proprietary information.

Additionally, the financial compliance provisions do not provide strict limitations on which individuals within the HECO Companies will have access to the developer's financial information. Prior to requiring the developer to submit to an audit, the Company should be required to make a showing that the audit is required. This can be done through an opinion issued to the developer from the Company's outside legal counsel or auditor that an audit is necessary for the Company's compliance requirements.

Additionally, the HECO Companies should strictly limit access to any information obtained by the Companies to only those persons involved with compliance matters. Section 24.2 should be revised to provide that no persons involved in such compliance matters should be permitted to: (a) participate in any HECO Company-owned or affiliated entities whose business is the development or generation of renewable energy; or (b) disclose any information to any person outside of the audit group.

Article 30, Miscellaneous, PPA at 59-66

Section 30.20 provides that if, during the Term, any "standard, system, or organization" referenced in the PPA should be modified or replaced in the normal course of events, such modification or replacement shall be used instead. The terms, "standard, system, or organization" are broad and ambiguous and should be clarified, or Section 30.20 should be removed.

Section 30.9 preserves the Company's ability to exercise its rights as specified in the Company's Tariff as filed with the Commission, or as specified in General Order No. 7 of the Commission's Standards for Electric Utility Service in the State of Hawaii. HREA recommends adding the phrase, "or the Seller's" after "the Company's" in this section to make the provision reciprocal. In addition, to provide certainty to developers, language should be added to provide that "the Company waives any right to challenge the validity of the PPA based on any theory, under the Public Utility Regulatory Policies

Act of 1978, or otherwise, or that the Commission does not have the authority to require the Company to offer to enter into, or enter into, the PPA."

HREA also recommends that the PPA include a provision regarding transfer of title and risk of loss for the energy from the Seller to the Company at the Point of Interconnection. Furthermore, the PPA should provide for renegotiation in the event of any change in law that significantly affects a party's ability to perform under the PPA.

Attachment B, Performance Standards, PPA at B-11-B16

Attachment B, Section 3, designates certain performance standards for the Seller's Facility, which the HECO Companies, in their sole discretion, will determine. While the HECO Companies may assert that the IRS results will inform what performance standards will be, the reality is, the HECO Companies' ultimately control the IRS process, the IRS report, and the final determination of performance standards. Indeed, the following bracketed language appears throughout Attachment B: "[THESE REQUIREMENTS MAY BE CHANGED BY THE COMPANY UPON COMPLETION OF THE IRS]" (emphasis added).

Allowing the Company to maintain the sole discretion over performance standards introduces a significant amount of risk for the developer which will not be resolved until very late in the development process, i.e., when the multi-month IRS process is completed. In this regard, one of the major goals of the FIT – to create a certain and predictable process under which renewable energy will be purchased by the utilities – will be difficult to achieve. Furthermore, this structure permits the HECO Companies to arbitrarily impose overly stringent performance standards on projects, making them unbuildable in light of the FIT energy rates to be paid, which would defeat many of the goals the Commission established for the FIT program, such as larger project size limits and system caps.

Section 3(C) of Attachment B establishes certain ramp rate requirements, which may be problematic for FIT developers. Intermittent generators do not have the ability to limit downward variations in their output without the installation of additional equipment. The HECO Companies' concern about ramp rates and power fluctuation rates is not unique to the HECO Companies' island setting. Uncontrolled variations in output have the potential for adverse impacts on system frequency. Variations in system frequency are typically managed using AGC and Frequency Regulation (Spinning Reserves).

As the HECO Companies' proposal would require intermittent generators to install additional equipment, there will be a time delay between output variation from the generator and compensation by the additional equipment. This time delay may be long enough to trigger the HECO Companies' automatic Frequency Regulation schemes. Two sets of equipment independently compensating for the same output variation will cause further swings in system frequency, which is clearly not a desired outcome. This methodology degrades system reliability, as it does not have central control, and is the least cost effective as it only addresses individual projects rather than the needs of the entire island.

A more reliable and cost effective mechanism for addressing variations in the output of intermittent generators is the same method used to address variations in system load. Centralized frequency regulation units should be employed which manage the entire grid rather than individual projects. For example, the Alaskan Railbelt utilities operate on an "islanded" system of 800 MW, which is not connected to any bulk power grid. Their strategy for implementing additional intermittent generation is to install a central frequency regulating system to manage the additional variability on their system. This was identified as the most reliable and cost effective solution for their system, which serves less load than the HECO Companies' System, is less integrated than the HECO Companies' System, and has no connections to a larger bulk power grid.

Section 3(A), Reactive Power Control, likewise presents problems for FIT developers. Section 3(A) gives the Company the open-ended right to designate voltage or power factor control, presumably throughout the Term of the PPA. The majority of commercially available inverters can provide power factor control. Only a limited number of inverters have the ability to provide voltage control. The Seller will need to select an inverter prior to beginning the IRS. Voltage or power factor controls should be specified prior to initiating an IRS. Based on HREA's inquiry to developers with projects on the mainland, unclear and confusing requirements on the part of the utility are a contributing cause to the interconnection queue backlogs seen on the mainland. Accordingly, an attempt should be made to avoid them here.

Attachment G, Company-Owned Interconnection Facilities

- Section 5, PPA at G-7 – Section 5 of Attachment G requires the developer to provide a standby letter of credit to the Company to secure the developer's obligations to pay for Company-owned interconnection facility costs. This requirement for a standby letter of credit is unnecessary because under Section 2(B) of Attachment G, the developer must pay: (a) the first $10,000 of all interconnection costs upon the execution of the PPA, and (b) the balance of the interconnection costs within 30 days after the execution of the PPA. Thus, by 30 days after the execution of the PPA, all of the interconnection costs will be paid by the developer. From a practical standpoint, by the time the standby letter of credit is due, all interconnection costs will have been paid by the developer, obviating the need for the security provided by the letter of credit.

- Section 6, PPA at G-8 – Section 6 provides that upon termination of the PPA, the developer must remove all of the developer-owned interconnection facilities from the project site, and that the developer restore the project site to its condition prior to construction of the project, within 90 days after termination of the PPA. Removal of facilities requirements and restoration of project site requirements are generally negotiated between the developer and its lessor and contained in the terms of the ground lease or other land tenure instrument. To the extent the PPA contains provisions relating to the developer's obligations with respect to the land, those provisions may conflict with the developer's obligations under its lease or other land tenure instrument. Accordingly, these provisions should be removed from the PPA.

- Section 9, PPA at G-10 – Section 9 requires the Seller to use commercially reasonable efforts to obtain perpetual Land Rights. Section 8 further provides that such Land Rights contain terms and conditions which are acceptable to Company and shall be provided to Company in advance for its review. While it may be customary for a developer to provide the Company with a representation or warranty that it has Land Rights, providing the Company with the sole right to review and approve a developer's land rights is unnecessary and introduces another potential source of delay for the development of a FIT project. The Seller's obligation should be limited to providing a representation or warranty that it has Land Rights, or providing the Company with a short form copy of the Lease.

Attachment L, Reporting Milestones

As noted earlier above, Attachment L establishes certain reporting milestones that a developer must meet. Attachment L leaves the date of such Reporting Milestones blank. It is unclear which party will determine what those dates are, but presumably, a developer will propose dates based on its project schedule, which the Company must ultimately approve.

If milestone dates are left open to negotiation, such open-endedness would run counter to the certainty the FIT program is intended to achieve. Furthermore, if negotiation of milestone dates occurs at the end of the FIT PPA process (as is typically the case in bilateral PPA negotiations), the developer would be left with unequal bargaining power. At that stage, the developer would have invested significant resources to secure land, entitlements, and necessary permits, and would be reluctant to argue against the utility's preference (even if unreasonable) for certain milestone dates for fear of losing the project.

Attachment L also requires the developer to provide the Company with an executed copy of the engineering, procurement, and construction ("EPC") agreement. Since the EPC agreement will likely contain confidential business terms, the developer should not be required to submit a copy to the Company. Under the PPA, the HECO Companies should have ample assurance that a developer will meet its obligations under the PPA. A developer already runs the risk of default under the PPA if it fails to meet the Guaranteed In-Service Date. Furthermore, the developer has every incentive to complete construction in a timely manner; otherwise, it will not receive payment for energy.

5. CONCLUSION

HREA reiterates that it appreciates the HECO Companies' efforts to make the Tier 3 pricing process as transparent and collaborative as possible. Nonetheless, for the reasons set forth above, HREA has concerns about the levered approach and various assumptions that have been used in the Model.

In addition, HREA believes the proposed payment rates are too low to stimulate a market response to achieve the goals of the FIT program. Specifically with respect to wind, HREA recommends a rate in the range of **25.1 cents/kWh to 31.5 cents/kWh,** which assumes 0% debt, no monetization of the REITIC and an internal rate of return of 15% and 19% respectively.

With respect to the PPA, HREA has substantial concerns about many of the provisions contained in the PPA and believes that if the PPA is approved as proposed, it will be extremely difficult for developers to finance and develop solar and wind projects in the Tier 3 range.

Without resolution of these issues, a successful "rollout" of the FIT program is in jeopardy. Further, the goal of the FIT program – to create a predictable and streamlined procurement mechanism to dramatically accelerate the HECO Companies' purchase of renewable energy, and thereby decrease Hawaii's dependence on foreign oil – may not be achieved.

HREA appreciates the opportunity to submit its comments and recommendations to the Commission regarding the HECO Companies' Tier 3 Proposal.

<This concludes our comments and recommendations>

DATED: May 20, 2010. Honolulu, Hawaii

Warren S. Bollmeier II, President
Hawaii Renewable Energy Alliance

ATTACHMENT "A"
Estimated Land Cost and Lease Escalation

Land costs for industrial-zoned properties in the Campbell Industrial Park range from $16 per square foot ("PSF") to $32 PSF. [13]
Accordingly, the average land cost for industrial properties in the Campbell Industrial Park is $24 PSF, or $1,045,440 per acre.
The estimated range of lease revenues for industrial properties on Oahu based on publicly available market data is ~ 6%-8%.
Assuming a 7% of price per acre as lease revenues, estimated land lease costs for industrial properties per acre is ~ $73,181 per acre.
Therefore, the lease land cost escalated at 3% per year and applied every 5 years[14] is as follows:

Years	Lease (per acre)
1-5	$73,181
6-10	$84,837
11-15	$98,349
16-20	$114,013

[13] See C.B. Richard Ellis *Market View, Hawaii Industrial*, First Quarter, 2010, p.3., appearing on the following page.
[14] This formula can be found on Page 12 of the Hawaiian Electric Companies' Schedule FIT Tier 3 Tariffs and Agreement, filed April 29, 2010.

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Hawaii Industrial

First Quarter 2010

INDUSTRIAL VACANCY AT 8-YEAR HIGH

Vacancy levels rose in the first quarter of 2010 to their highest levels since early 2002. Although vacant space increased in this period it was a much slower increase than the two previous quarters. It's difficult to draw conclusions from such a short period of time but the market activity and economic activity seem to support the hypothesis that industrial vacancy is stabilizing.

Base rents in the Hawaii industrial leasing market continued to fall in the first quarter of 2010 to an overall weighted average of just $1.02 SF. This continues a negative trend that began in the first quarter of 2008 when average asking base rental rates peaked at just under $1.30 SF per month. CBRE expects the trend of decreasing rents to continue for the balance of 2010 but at a much slower rate.

Sales of industrial properties in the first quarter continued to be sluggish. A second large condo project is now in foreclosure and will be the subject of a bulk sale auction later in April. It is anticipated that the new owner will put these industrial condominiums back on the market for sale or for lease and this is reflected in the statistics we are reporting. If the pricing on these units reflects the ultimate sale price in foreclosure we can anticipate that the market will establish new lower sales comparables as a result.

CBRE expects that the Hawaii industrial market will further level in the balance of 2010 with slightly lower rents, a leveling of vacancy and a modest increase in sales volume but at lower prices and to owner-users.

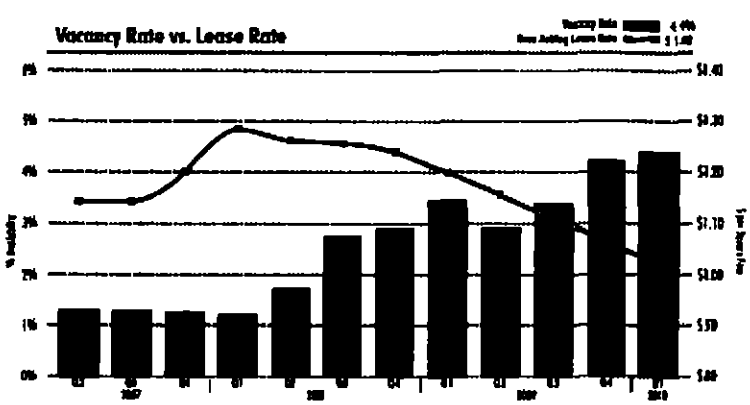
QUICK STATS

	Current	Change from last Yr.	Change from last Qtr.
Vacancy	4.4%	↑	↑
Base Lease Rates	$1.02	↓	↓
2010Q1 Absorption*	-23.9KSF	↓	↓

* [illegible]

HOT TOPICS

- Industrial vacancy is 4.4 percent, an increase of 1.0% percentage point over the last twelve months.
- Base average asking rents decreased $.18 to $1.02 since Q1 of 2009.
- Industrial absorption for the first quarter is negative 23,926 SF.
- The average price per square foot for industrial land decreasing.



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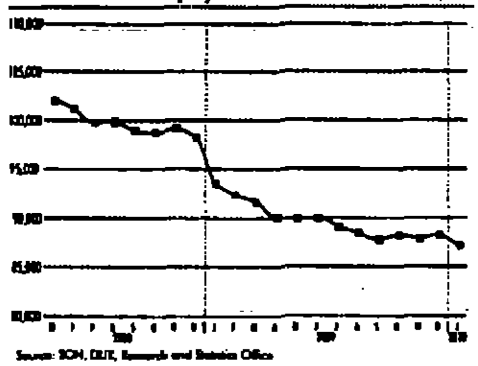
Hawaii Industrial Market

Submarket	Net Rentable Area	Vacant Area	Vacancy Rate	Absorption Q1	Weighted Average Asking Rents Op Exp	Base	Gross
Kakaako	1,700,412	130,712	7.7%	(69,395)	$ 0.45	$1.07	$ 1.52
Iwilei	3,483,658	152,263	4.4%	(80,123)	$ 0.42	$1.10	$ 1.52
Kalihi	7,029,067	294,140	4.2%	264,610	$ 0.33	$0.92	$ 1.25
Mapunapuna	1,641,874	64,535	3.9%	48,939	$ 0.20	$1.09	$ 1.29
Airport	4,828,645	84,497	1.7%	67,077	$ 0.48	$0.96	$ 1.44
[illegible]	621,337	2,471	0.4%	(788)	$ 0.29	$1.25	$ 1.54
Halawa	2,386,852	120,184	5.0%	18,717	$ 0.24	$1.07	$ 1.31
Pearl City	973,166	69,083	7.1%	50,649	$ 0.26	$1.11	$ 1.37
Waipio / Mililani	1,781,677	205,510	11.5%	(6,972)	$ 0.46	$1.04	$ 1.50
Waipahu	2,632,341	200,613	7.6%	(42,708)	$ 0.28	$0.99	$ 1.27
Kapolei	1,080,720	495,259	45.8%	(229,690)	$ 0.25	$0.91	$ 1.16
Campbell/Kapolei	4,964,132	244,960	4.9%	(25,852)	$ 0.26	$0.81	$ 1.07
Windward	973,837	73,584	7.6%	20,583	$ 0.32	$1.04	$ 1.36
Oahu	34,327,569	2,146,862	6.3%	5,991	$ 0.36	$1.04	$ 1.40
Maui	10,723,580	43,620	0.4%	19,871	$ 0.26	$1.22	$ 1.48
Big Island	9,079,769	198,618	2.2%	(34,568)	$ 0.25	$0.84	$ 1.09
Kauai	1,852,587	62,723	3.4%	(15,220)	$ 0.29	$0.96	$ 1.25
State	55,983,905	2,451,373	4.4%	(73,926)	$ 0.32	$1.02	$ 1.34

Industrial Sector Employment

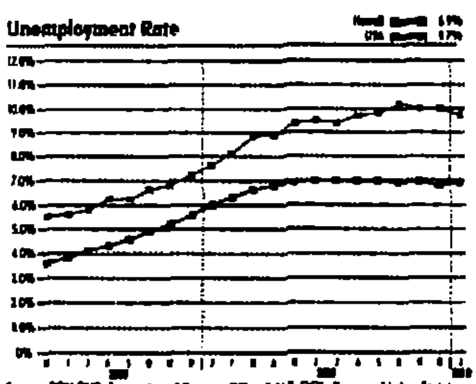


The Hawaii employment level for January 2010 is 579,450 people employed. After the December 2007 peak, jobs have declined by 55,750. The seasonal trends still shape the graph, and the decline since the peak returns it to levels last seen in early 2004.

Industrial sector employment also reached an all time high in December 2007 with 107,100 people employed. Since that peak, and with seasonal trends, the number of people employed in industrial jobs declined and is now 87,200 people, matching mid 2003.

Employment in the office and retail sectors have followed similar trends, with office jobs at 104,350 and retail at 200,650.

Unemployment Rate



The unemployment rate in Hawaii for January 2010 was reported at 6.9 percent, which is 0.9 percentage points above the beginning of 2009. The level has been steady for most of the year. This equates to a currently unemployed work force in Hawaii of nearly 45,000 people.

Unemployment last peaked in November 2001 at 5.2 percent. After a bottom of 2.2 percent in December 2006, it had been climbing, however during 2009, it leveled off.

Nationally, unemployment has also been climbing at a comparable rate, and in January it is reported to be 9.7 percent. This represents a national unemployed labor force of approximately 15.4 million people, an increase of 3.5 million this year.

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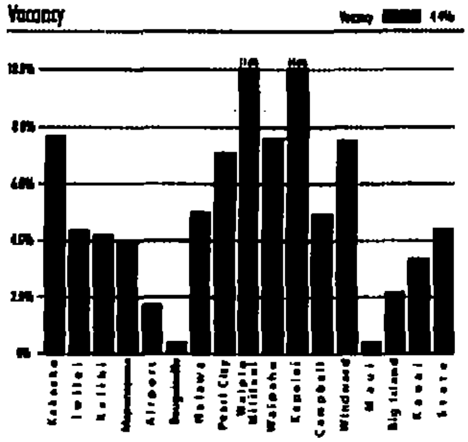
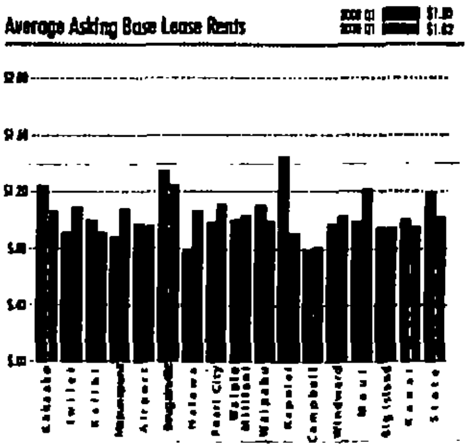
Vacancy



Vacant industrial space in Hawaii has been increasing for two years and is now 4.4 percent. There is 2,451,323 SF of vacant industrial space available for lease in Hawaii. This space includes 2,146,862 SF on Oahu and 304,461 SF on the neighbor islands.

Submarkets with the most available space are Kalihi, Waipio, Waipahu, Kapolei and Campbell, each with more than 200,000 SF on the market. The vacancy rate in Kapolei is high, now that the Kalaeloa data has been integrated into the survey.

Average Asking Base Lease Rents

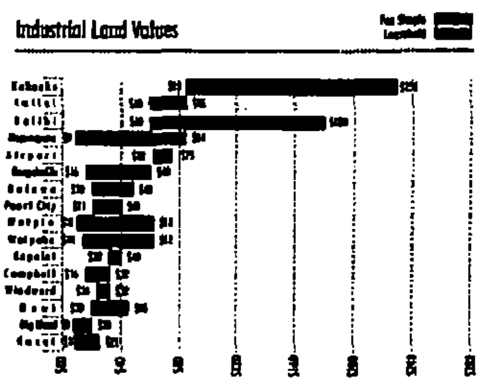


The weighted average asking base lease rate for Hawaii decreased to $1.02 pSF/month over the last twelve months, after peaking at $1.28 in the first quarter of 2008. The current asking rent is even with year-end 2005.

Average asking base rents are weighted with the vacancy to keep small expensive properties (for example) from skewing the data. So, when as vacant space changes, the asking rates will follow.

The rents over the past several years have been moving between $1.05 and $1.29 depending on availability and landlords efforts to attract and renew tenants.

Industrial Land Values



Industrial property transaction activity continues to be slow moving with the number of transactions staying relatively low. There are a few transactions in some of the submarkets that have higher than normal prices, but nothing significant enough to drive up the overall average. There were 72 significant transactions of 76 industrial parcels totaling 2.8M square feet, with a total consideration of $113M over the last six months. The most active submarkets are Bougainville and Kalihi.

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MarketView Hawaii Industrial

Hawaii Submarket Map

HAWAII INDUSTRIAL Property	Parcels	Improved Industrial Land Condos	Improved Industrial Land Bldg SF	Improved Industrial Land Land SF	Vacant Industrial Land Parcels	Vacant Industrial Land Land SF	All Industrial Land SF
Kakaako	120	15	1,702,412	2,105,378	142	8,244,771	10,349,599
Iwilei	47	44	3,403,458	4,408,557	605	2,978,472	7,405,029
Kalihi	292	147	7,079,062	24,521,954	325	18,140,878	42,662,782
Mapunapuna	65	-	1,640,824	2,738,101	71	2,865,384	5,603,485
Airport	196	107	4,878,645	9,575,986	185	115,390,943	124,966,905
Kapalama	9	-	671,537	337,192	7	1,474,749	1,711,941
Halawa	45	-	2,306,052	2,612,926	64	3,032,654	5,645,580
Pearl City	39	-	973,166	3,097,413	10	4,045,108	7,142,521
Waipio - Mililani	45	1	1,781,677	2,737,940	58	2,393,591	5,131,531
Waipahu	22	-	2,452,341	5,445,972	93	5,141,819	10,827,791
Kapolei	75	-	1,080,720	14,905,227	40	6,133,289	21,038,516
Campbell	137	4	4,964,137	43,364,435	140	55,552,807	98,921,242
Windward	49	-	973,832	2,877,183	11	3,324,894	6,202,077
Maui	532	-	10,773,580	84,670,711	884	114,142,718	198,812,429
Big Island	557	28	9,879,769	220,034,089	811	141,888,107	361,922,182
Kauai	120	17	1,452,587	146,791,095	152	650,057,624	796,848,719
State of Hawaii	2,390	483	55,113,505	572,236,986	4,033	1,158,065,066	1,730,302,052

Hawaii Local Offices and Advisors

HONOLULU, OAHU
[illegible]

KAHULUI, MAUI
[illegible]

KAPAA, KAUAI
[illegible]

KAILUA-KONA
[illegible]

Joseph T. Hoss (B) SIOR
Managing Director
[illegible]

Trenton J. Thome (B)
Associate
[illegible]

George I. Lucey (B)
[illegible]

Grant Davidson (S)
Associate
[illegible]

Peter Grossmann (S)
[illegible]

Elizabeth P. Pearson (S)
[illegible]

Frank E. Salmeson, Jr. (S)
[illegible]

Lani M. Olanb (S)
[illegible]

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HAWAII INDUSTRIAL MARKET BASIS
Includes improvements on property that is listed or zoned for industrial use in Hawaii, excluding buildings that are under construction.
NET RENTABLE AREA
The total floor area of the building or project
UNDER CONSTRUCTION
Buildings which have begun construction as evidenced by site excavation or foundation work.
VACANCY RATE
Vacant Space Feet divided by NRA
VACANT SQUARE FEET
Existing Building Area which is physically vacant or immediately available
NORMALIZATION
Due to a reclassification of the market, the base, number and square footage of buildings for previous quarters have been adjusted to match the current base. Vacancy figures for those buildings have been adjusted in previous quarters.
LAND VALUES
Low and high land values are determined by applying the properties of the assessed values for land and improvements to the last sales price and dividing by gross square footage. This method is effective for estimation only and used for the construction of trends, and may not represent actual property values.

For more information regarding this MarketView, please contact:
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HECO Companies' Analysis

Tier 3 Wind Resources
100kW-5MW

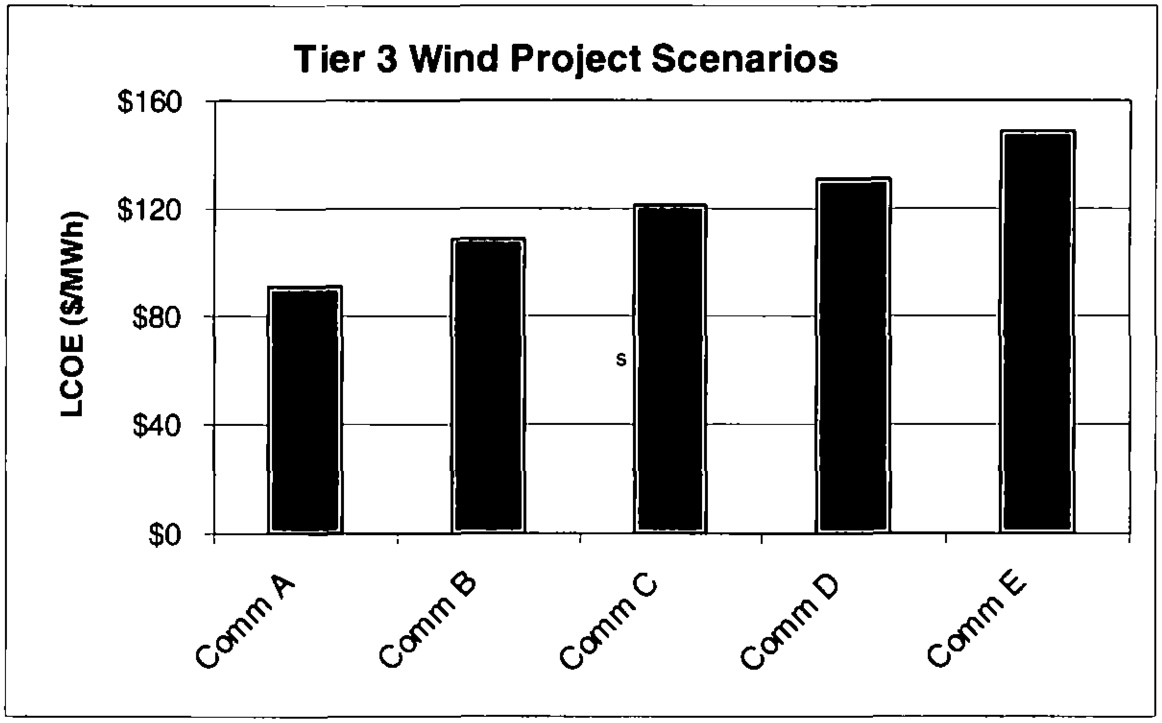
	Scenarios				
Inputs	*Comm A*	*Comm B*	*Comm C*	*Comm D*	*Comm E*
Size (kW)	5,000	5,000	2,500	1,000	1,000
Production (kWh/kW)	3,154	2,978	2,803	2,628	2,453
Curtailment (%/year)	0%	0%	0%	0%	0%
Contract life	20	20	20	20	20
System life	20	20	20	20	20
Capacity factor (after losses)	36%	34%	32%	30%	28%
Capital Costs					
Turbines ($/kW)	$ 2,000	$ 2,100	$ 2,300	$ 2,400	$ 2,600
Site Development & Construction ($/kW)	$ 1,500	$ 1,400	$ 1,300	$ 1,200	$ 1,100
Permitting and Fees ($/kW)	$ 100	$ 100	$ 200	$ 500	$ 500
Freight/Excise ($/kW)	$ 194	$ 204	$ 224	$ 233	$ 253
Interconnection/Electrical ($/kW)	$ 255	$ 255	$ 290	$ 530	$ 530
Total Installed ($/kW)	$ 4,049	$ 4,059	$ 4,314	$ 4,863	$ 4,983
O&M Costs					
O&M ($/kW/year)	$ 25.00	$ 30.00	$ 30.00	$ 30.00	$ 40.00
Land lease (% royalty on revenues)	4%	4%	4%	4%	4%
Other Costs					
Insurance (% CapEx/year)	0.6%	0.6%	0.6%	0.6%	0.6%
Property Tax ($/year)	$ -	$ -	$ -	$ -	$ -
Financing					
Debt percentage (%)	35%	35%	35%	35%	35%
Debt rate (%)	9%	9%	9%	9%	9%
Debt tenor (years)	20	20	20	20	20
Construction Debt Percentage	80%	80%	80%	80%	80%
Construction Loan Rate	11%	11%	11%	11%	11%
Construction Period (months)	10	10	6	4	4
Equity rate (%)	11%	11%	11%	11%	11%
Tax Incentives					
Depreciation Years	5	5	5	5	5
PTC ($/MWh) for 10 years	$ 21	$ 21	$ 21	$ 21	21
Federal ITC (%)	30%	30%	30%	30%	30%
State ITC (%)	20%	20%	20%	20%	20%
# of systems	10.00	6.00	3.00	4.00	2.00
Tax Rate (all in)	40.0%	40.0%	40.0%	40.0%	40%

<u>*LCOE PRICES ($/MWh)*</u>

B&V Model	$91	$109	$121	$131	$149

Midpoint of Range (Proposed tariff) **$120**

(see chart on next page)



HREA Comments:

Performance and Cost Factors

1. Capacity factor of 32% is acceptable. The Companies have not stated so specifically, but HREA assumes that the 28% to 36% range might represent design-specific differences. However, HREA does not believe there would be that much of a range in capacity factors.

2. Costs. HREA estimates the installed costs for a 2.5 MW project to be about $4,500. If one assumes the high and low of $4,049 to $4,983, the average would be about $4,516.

   For the purposes of this discussion, HREA accepts the Companies' 2.5 MW cost of $4,314/kW as the average Tier 3 cost for a wind project.

3. O&M costs. HREA is unable to determine at this time whether a "fixed" annual O&M costs figure of $40/kW-year is appropriate.

4. Land Costs. 4% of gross revenues is appropriate. However, the Companies have not clarified that it is 4% of gross revenues, as opposed to net revenues.

5. Insurance. 0.6% is appropriate.

6. Taxes. Currently there is no property tax for renewable projects on Oahu.

Financing Assumptions

1. Debt Percentage. 35% may be appropriate for some projects.

2. Debt Rate. 9% may be appropriate for some projects.

3. Debt Tenor. 20 year loans are not available for wind projects. 10 year loans may be more likely, if available in the near term.

4. Equity. 11% will not attract investors and is therefore not appropriate for the FIT. 15% to 19% is an appropriate ROE range to attract investors to Hawaii.

5. Other Factors: The Companies' analysis does not account for debt service coverage ratio requirements that are normally imposed by lenders.

Given the above, there are simply too many variables in the financial model that are uncertain. Therefore, HREA supports the use of the "unlevered" financial analysis, as first proposed in the FIT docket by the Blue Planet Foundation.

Tax Incentives

1. The federal ITC is preferred, and is refundable, in the near term.

2. Developers will not be able to monetize the state renewable energy tax credit, as it is NOT refundable for wind. Payment rates should therefore be based on NO state tax credit.
   The Companies assumption that separate state tax credits can be taken on each wind turbine is NOT appropriate.
   To HREA's knowledge, the Dept. of Taxation has not allowed a "by the turbine" tax treatment.

Bottom-Line: The Companies' offer of 12 cents/kWh is too low to encourage development
The primary reasons for this low rate appear to be the inappropriate financial and tax incentive assumptions that are made by the Companies.

Per HREA's analysis on the next two charts, HREA recommends a payment rate in the range of **25.1 cents/kWh to 31.5 cents/kWh.**

Note: The Commission's D&O did not show Tier 2 wind above 100 kW.
HREA believes, as suggested by the Companies, that 100 kW to 5 MW wind projects should be eligible for the FIT program on Oahu.

Cost of Generation Calculator
All inputs are in blue.

Wind Tier 3 Project - COMMERCIAL - 2.5 MW
(Unlevered Case: 15% ROE)

Technology Assumptions	
Project Capacity (MW)	2.5
Capital Cost before const. financing ($/kW)	$4,314
Capital Cost incl const. financing ($/kW)	$4,378
Fixed O&M ($/kW)	$40
Fixed O&M Escalation	2.5%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	2.5%
Insurance (% CapEx/year)	0.60%
Fuel Cost ($/MBtu)	$0
Fuel Cost Escalation	2.5%
Land (% royalty on revenues)	4.0%
Heat Rate (Btu/kWh)	0
Production Degradation (%/year)	0.00%
Capacity Factor	32%

Financial/Economic Assumptions	
Debt Percentage	0%
Debt Rate	9.0%
Debt Term (years)	20
Construction Debt Percentage	80%
Construction Loan Rate	11.0%
Construction Period (months)	4
Economic Life (years)	20
% of Plant at 5-yr MACRS	89%
% of Plant at 7-yr MACRS	0%
% of Plant at 15-yr MACRS	0%
% of Plant at 20-yr MACRS	11%
Cost of Generation Escalation	0.0%
Federal Tax Rate (marginal)	35.000 %
State Tax Rate (effective)	6.015%
State Excise Tax Rate (wholesale)	0.500%
Cost of Equity	15%
Discount Rate	9%

Incentives		Cap
PTC ($/MWh)	$0	
PTC Escalation	0.0%	
PTC Term (years)	0	
Federal ITC	30.0%	
State Tax Credit	0.0%	$500,000
No. of Systems (WTGs) GV	1	

Results	
NPV for Equity Return	$0
IRR of Equity Cash Flows	15%
Levelized Cost of Generation	$250.73

Cost of Generation Calculator
All inputs are in blue.

Wind Tier 3 Project - COMMERCIAL - 2.5 MW
(Unlevered Case: 19% ROE)

Technology Assumptions	
Project Capacity (MW)	2.5
Capital Cost before const. financing ($/kW)	$4,314
Capital Cost incl const. financing ($/kW)	$4,378
Fixed O&M ($/kW)	$40
Fixed O&M Escalation	2.5%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	2.5%
Insurance (% CapEx/year)	0.60%
Fuel Cost ($/MBtu)	$0
Fuel Cost Escalation	2.5%
Land (% royalty on revenues)	4.0%
Heat Rate (Btu/kWh)	0
Production Degradation (%/year)	0.00%
Capacity Factor	32%

Financial/Economic Assumptions	
Debt Percentage	0%
Debt Rate	9.0%
Debt Term (years)	20
Construction Debt Percentage	80%
Construction Loan Rate	11.0%
Construction Period (months)	4
Economic Life (years)	20
% of Plant at 5-yr MACRS	89%
% of Plant at 7-yr MACRS	0%
% of Plant at 15-yr MACRS	0%
% of Plant at 20-yr MACRS	11%
Cost of Generation Escalation	0.0%
Federal Tax Rate (marginal)	35.000 %
State Tax Rate (effective)	6.015%
State Excise Tax Rate (wholesale)	0.500%
Cost of Equity	19%
Discount Rate	9%

Incentives		Cap
PTC ($/MWh)	$0	
PTC Escalation	0.0%	
PTC Term (years)	0	
Federal ITC	30.0%	
State Tax Credit	0.0%	$500,000
No. of Systems (WTGs)	1	

Results	
NPV for Equity Return	$0
IRR of Equity Cash Flows	19%
Levelized Cost of Generation	$315.23

Cost of Generation Calculator

All inputs are in blue.

Wind Tier 3 Project - COMMERCIAL - 2.5 MW

Levered - 10 yr loan - 19% ROE

Technology Assumptions	
Project Capacity (MW)	2.5
Capital Cost before const. financing ($/kW)	$4,314
Capital Cost incl const. financing ($/kW)	$4,378
Fixed O&M ($/kW)	$40
Fixed O&M Escalation	2.5%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	2.5%
Insurance (% CapEx/year)	0.60%
Fuel Cost ($/MBtu)	$0
Fuel Cost Escalation	2.5%
Land (% royalty on revenues)	4.0%
Heat Rate (Btu/kWh)	0
Production Degradation (%/year)	0.00%
Capacity Factor	32%

Financial/Economic Assumptions	
Debt Percentage	35%
Debt Rate	9.0 %
Debt Term (years)	10
Construction Debt Percentage	80%
Construction Loan Rate	11.0%
Construction Period (months)	4
Economic Life (years)	20
% of Plant at 5-yr MACRS	89%
% of Plant at 7-yr MACRS	0%
% of Plant at 15-yr MACRS	0%
% of Plant at 20-yr MACRS	11%
Cost of Generation Escalation	0.0%
Federal Tax Rate (marginal)	35.000%
State Tax Rate (effective)	6.015%
State Excise Tax Rate (wholesale)	0.500%
Cost of Equity	19%
Discount Rate	9%

Incentives		Cap
PTC ($/MWh)	$0	
PTC Escalation	0.0%	
PTC Term (years)	0	
Federal ITC	30.0 %	
State Tax Credit	0.0%	$500,000
No. of Systems (WTGs)	1	

Results	
NPV for Equity Return	$(
IRR of Equity Cash Flows	19%
Levelized Cost of Generation	$234.9(

CERTIFICATE OF SERVICE

The foregoing HREA Comments and Recommendations was served on the date of filing by Hand Delivery or electronically transmitted to each such Party as follows.

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DATED: Honolulu, Hawaii, May 20, 2010